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Using market-based dispatching with environmental price signals to reduce emissions and water use at power plants in the Texas grid

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Abstract

The possibility of using electricity dispatching strategies to achieve a 50% nitrogen oxide (NO_x) emission reduction from electricity generating units was examined using the grid of the Electricity Reliability Council of Texas as a case study. Simulations of a hypothetical policy demonstrate that imposing higher NO_x prices induces a switch from some coal-fired generation to natural gas generation, lowering NO_x emissions. The simulation is for a day with relatively high electricity demand and accounts for transmission constraints. In addition to the lowering of the NO_x emissions, there are co-benefits of the redispatching of generation from coal to natural gas, including reductions in the emissions of sulfur oxides (24%–71%), Hg (16%–82%) and CO₂ (8.8%–22%). Water consumption was also decreased, by 4.4%–8.7%. Substantial reductions of NO_x emissions can be achieved for an increased generation cost of 4–13%, which is due to the higher fuel price of gas relative to coal (assuming a price of \$3.87 per MMBTU (MMBTU: million British thermal units) for natural gas, and \$1.89 per MMBTU for coal). However, once the system has reduced NO_x emissions by approximately 50%, there is little incremental reduction in emissions due to further increases in NO_x prices.

Keywords: NO_x, electricity generation, SO_x, air quality

1. Introduction

Electricity generation accounted for approximately 21% of emissions of nitrogen oxides (NO_x) in the United States in 2005; electricity generation units (EGUs) are also major

sources of sulfur oxides (SO_x) (in particular, sulfur dioxide (SO₂)) and mercury (Hg) emissions (EPA 2011a). Further, thermoelectric power generation impacts water resources due to water demand for cooling and condensing the steam generated in boilers (Kenny *et al* 2009, Solley *et al* 1998).

Water use by thermoelectric power generation accounts for approximately 41% of freshwater withdrawals in the United States (Kenny *et al* 2009).

A number of air quality regulations have led to reductions in air pollutant emissions from EGUs in the United States, and recently the US Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule, which calls for additional reductions in the emissions of NO_x and SO_x from EGUs in 27 eastern states (EPA 2011b). Because these emission reductions are proposed to be implemented relatively rapidly, the long-term (multi-year) solution of installing additional emission controls for NO_x and SO_x at existing EGUs might not be able to achieve the regulated schedule for reductions. Thus, other schemes for achieving emission reductions in the short term might be necessary. The analysis presented here examines one such scheme, namely market-based dispatching in the electricity sector, as a means of rapidly reducing emissions. The approach proposed herein uses market-oriented price signals for NO_x emissions to switch generation from high NO_x emitting facilities to low NO_x emitting facilities. These price signals, by increasing the costs associated with NO_x emissions, would act to change the relative dispatch order (or merit order), lowering the merit order of high NO_x emitting facilities relative to low NO_x emitting facilities. This market-based environmental pricing could enable substantial NO_x reductions immediately and in the absence of additional control technologies or alternative generation technologies. Such prices could be induced either through (1) a uniform emissions tax, or, (2) a tradable emissions permit system within a region under a tighter seasonal or annual cap than currently exists. Theoretically, the price and the quantity (cap) approach would yield identical emissions and total costs, but would yield different distributions of costs across stakeholders (Kolstad 2000). The simulated price mechanisms presented below would require a change to the existing policy structure.

Using price signals to induce emissions reductions from EGUs is not new. For more than a decade, emissions from electric power generation have been subject to a variety of cap and trade programs. Examples of cap and trade programs in the United States include the Acid Rain Program, the Clean Air Interstate Rule (CAIR), and the NO_x Budget Trading Program (EPA 2011a). By 2008, implementation of Acid Rain Program regulations had yielded reductions of SO₂ emissions of 51% compared to 1990 levels (EPA 2011a); ozone season NO_x emissions decreased by 60% between 2000 and 2007 due to the NO_x Budget Trading Program (EPA 2011a).

However, most of these emissions reductions were the consequence of longer term investments in pollution control equipment, fuel switching (e.g., higher sulfur to lower sulfur coal), and new generation (Ellerman *et al* 2000). Additional short-term approaches could include time-varying price signals to induce redispatching among current (fixed) generation options. Several studies have simulated the potential of such approaches. For example, Nobel *et al* (2001) examined a NO_x emission trading program in eastern Texas. Sun *et al* (2011) and Martin *et al* (2007) examined the impact of NO_x pricing on emission trading in the Pennsylvania–New Jersey–Maryland (PJM) region.

Percentage of 319 TWh Electricity generation in ERCOT (2010)

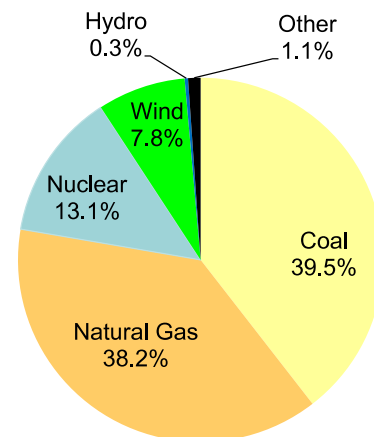


Figure 1. Relative contribution to electricity generation in ERCOT in 2010 by fuel type (ERCOT 2011).

This work examines whether additional reductions in NO_x emissions (up to 50%) from EGUs is possible using dispatching from high to low NO_x EGUs. This analysis has relevance to the Cross-State rule, but is not intended to address all of the specific requirements of the rule. The grid serving much of Texas (operated by the Electricity Reliability Council of Texas, ERCOT) is used as a geographical testbed. NO_x pricing is used in a transmission constrained electricity model to determine the price levels required to drive emissions from high to low NO_x EGUs.

Analyses presented in this work show that the imposition of higher NO_x prices can cause lower NO_x emissions within the current system by inducing a switch from some coal-fired generation to natural gas generation. The analyses are performed for a day with relatively high electricity demand and account for transmission constraints. In addition to lowering NO_x, there are co-benefits of the redispatching of generation from coal to natural gas, including reductions in the emissions of SO_x, Hg, and CO₂, and water consumption. However, once the system has achieved approximately 50% NO_x reduction, there is little incremental emission reduction due to further increases in NO_x prices, which instead simply drive up the emissions fees.

2. Methods

2.1. The Electricity Reliability Council of Texas (ERCOT)

The ERCOT electricity grid is wholly contained within the State of Texas, covering 75% of Texas land area. It serves 85% of the state's electric load (ERCOT 2011) and has 87% of the state's generation capacity. ERCOT has more than 500 generation units, with diverse fuel types, including natural gas (with steam cycles, open cycles and combined cycles), coal, nuclear, hydroelectric, petroleum, wind and solar. Figure 1 shows the electricity generation by fuel type for the ERCOT grid in 2010. As in most power systems, coal and nuclear

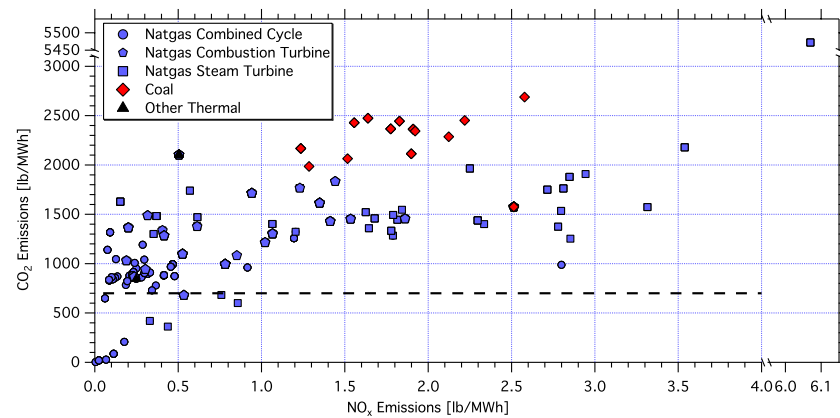


Figure 2. A comparison of NO_x and CO₂ emission rates for EGUs in Texas shows that there are some power plants that have relatively low emissions for both species, and there are some power plants that have relatively high emissions for both species. Because of conventional accounting standards that partition emissions across different functions at cogeneration facilities, some EGUs report a CO₂ emissions rate lower than 700 lbs/MWh (noted with a horizontal dashed line in the figure).

dominate base load and natural gas is used for intermediate cycling and peak demand.

NO_x emissions from EGUs in Texas can vary widely, ranging from more than 5 lb/MWh of generation for inefficient natural gas peaking plants, to 0.005 lb/MWh for facilities with selective catalytic reduction (SCR) control technologies. This variation by three orders of magnitude in NO_x emission rates suggests that some NO_x emission reductions will be possible by shifting generation from high NO_x emitting EGUs to low NO_x emitting EGUs.

This dispatching from high NO_x to low NO_x facilities has the potential to cause changes in SO_x emissions, CO₂ emissions, Hg emissions and water use. For example, figure 2 compares NO_x emissions and CO₂ emissions for ERCOT facilities. Some facilities have high NO_x emissions and high CO₂ emissions while others have low NO_x emissions and low or high CO₂ emissions. The CO₂ emissions rate can vary by as much as a factor of two for a given NO_x emissions rate. Some natural gas fueled EGUs report very low CO₂ emissions rates, which is the consequence of conventional reporting standards that partition emissions across multiple functions (heating and power generation) at cogeneration facilities. These complex footprints of emissions mean that dispatching of electricity for one purpose (in this work, NO_x emission reductions) could have non-obvious implications, either positive or negative, for other environmental impacts.

2.2. Electricity generation modeling

Electricity dispatching within ERCOT was modeled using an optimal power flow model, which simulates the response of the electricity network within ERCOT to hourly demand scenarios. The model accounts for the costs of electricity generation and transmission line constraints. The model was extended in this work to incorporate NO_x pricing for each generation unit.

The optimal power flow model is a non-linear optimization algorithm that minimizes total (fixed plus variable) operating cost subject to a set of equality and inequality constraints, including meeting demand, enforcing transmission line constraints, generator unit minimum and maximum power

levels, and accounting for line losses. Instead of gradient-based and Newton solution methods, a linear programming (LP) approach was used, which allows the inclusion of inequality constraints (Alsac *et al* 1990). The basic approach is iterative, solving the load flow problem (Stott 1974), creating a linear objective function and linearizing constraints for those results, then solving the primal LP to get an improved solution for power output at each unit.

The network model of ERCOT used in this work is based on solved load flow cases obtained from ERCOT, consisting of roughly 5600 buses, 7000 branches (transmission lines between buses), and all generating units. Demand is modeled as loads on 3600 of the buses, capturing only the high-voltage transmission system and simplifying distribution networks as single nodes. The costs of generation are based on data in the Emissions and Generation Resource Integrated Database (eGRID) (EPA 2010b), particularly heat rates (efficiency), and using EIA data (EIA 2011) on fixed and variable operating and maintenance costs based on the primary fuel and technology of each unit. Natural gas and coal prices (\$3.87 and \$1.89 per million British thermal units (MMBTU), respectively) were obtained from historical data in EIA (2010).

Emissions are also included in the cost model for each generator. Emissions prices for NO_x and SO₂ are used in our analysis to simulate the annual and seasonal caps on emissions. Environmental economic theory establishes that identical emissions can be induced from an emissions cap with permit trading among units and under a tax or price instrument, and the market price under permit trading will be equal to the tax that induces emissions equal to the cap (Kolstad 2000). The variable cost of each unit includes the emissions price times its emissions rate. Historical values of permit prices yield dispatch behavior that is consistent with past observed generation patterns. This approach also allows hypothetical tightening of these emissions targets to be simulated by increasing the price. With a sufficient increase in emissions price, the least-cost ordering of the generating units can be changed, making higher emissions units relatively more expensive and lower emissions units relatively less expensive, thus changing the dispatch. The results of these analyses are described below.

2.3. Emissions and water use data

Data for air pollutant emissions (NO_x and SO₂) were developed based on hourly emissions for the Texas electricity generation units that reported to the EPA's Clean Air Markets Division under the Acid Rain program (ARP) in 2006 (EPA 2010a). For all sources that did not report to the ARP, Ozone Season Daily (OSD) emissions data for the year 2006, as reported to the State of Texas Air Reporting System (STARS) were used (TCEQ 2010). Electricity generation units that have output greater than 25 MW reported to the Acid Rain Program. Air pollution data in STARS were collected by Texas Commission on Environmental Quality (TCEQ) from more than 2000 industrial sites in Texas and were stored in the TCEQ system (TCEQ 2011). The most updated versions of the data available at the time the analyses were done were used in this analysis for both ARP and OSD emissions.

The Emissions and Generation Resource Integrated Database (eGRID) 2005 was used to develop data sets for CO₂ and Hg emissions (EPA 2010b), and was used as a confirmation of the ARP and STARS NO_x emissions data. After the analyses were completed, the Environmental Protection Agency (EPA) released the seventh edition of the Emissions and Generation Resource Integrated Database (eGRID2010 version 1.1). This version contains the complete release of year 2007 data. The analyses reported here used the 2005 eGRID data that was available at the time the analyses were done, however, the analyses presented here were repeated using the 2007 data. In general, the results were qualitatively similar. Additional details are available from the authors.

Total water consumption for a particular EGU designates water evaporated such that it is not directly reusable. That is, water consumption is the net result of withdrawal minus return flow. Data regarding water consumption at EGUs were based on consumption factors (gal/kWh) as reported in King *et al* (2008). These factors in King *et al* (2008) were obtained from information submitted by power plant operators to the Energy Information Administration via form EIA-767 (now form EIA-923) as well as to the Texas Water Development Board (TWDB) and TCEQ. This data set includes additional details that impact water consumption, such as fuel type, cooling technology (open-loop, closed-loop or air-cooling), and water source. When water consumption factors were combined with generation data in the analyses performed in this work, the water consumption rate was determined for each EGU.

Emissions were linked to water consumption rate and the electricity generation model using ORISPL codes (EPA 2010b). A cross-reference file was created manually to link emissions from Ozone Season Daily emissions data in the AIRS Facility Subsystem file (OSD afs file) (TCEQ 2010) and water consumption rate for each electricity generation unit. The plant code (ORISPL) was used to link the air quality and water resources databases to the electric power generation model for EGUs constructed through 2006. However, for electricity generation units that started operation post-2006, the linking was developed manually by matching the new EGUs by site name and generator ID (or ORISPL) code.

2.4. Cost estimation

In the optimal power flow model, generation is dispatched in a least-cost manner to meet demand, subject to physical constraints on generators and transmission. The cost of each generator i is modeled as:

$$c_i (\$/MWh) = H_i(pf_i + pn_i N_i + ps_i S_i) + O\&M_i \quad (1)$$

where H_i is its heat rate (MMBTU/MWh), pf_i is the price of fuel (\$/MMBTU), pn_i is the price of NO_x permits (\$/ton), N_i is the unit's NO_x emission rate (tons/MMBTU), ps_i is the price of SO₂ permits (\$/ton), S_i is the unit's SO₂ emission rate (tons/MMBTU), and $O\&M_i$ is the unit's variable operation and maintenance costs (\$/MWh). Thus, increasing the NO_x price changes the least-cost ordering (also called the merit order) for dispatch.

In the results shown below, the costs of the NO_x emissions are reported. However, the main focus is on the change in generation costs, without including the emissions price:

$$c_{i2} (\$/MWh) = H_i pf_i + O\&M_i \quad (2)$$

because the revenues from the NO_x price used as a redispatch mechanism could be recycled back to utilities or ratepayers in a variety of ways to produce a revenue-neutral scheme. The true costs of this strategy would be determined by the relative fuel prices, changes in generator efficiency (could be positive or negative), and any changes in O&M costs. These changes in generation costs are presented normalized by both the NO_x reductions (\$/ton) and normalized by MWh. These costs could also be potentially benchmarked against avoided capital costs for additional environmental controls, but those costs were not analyzed in the work presented here.

3. Results

3.1. NO_x emissions reductions

The electricity generation redispatching scenarios under different NO_x prices scenarios were modeled using the optimal power flow model. The scenarios consisted of increasing the NO_x emissions price from \$0/ton to \$2000/ton, \$10 000/ton, \$25 000/ton, and \$50 000/ton. SO_x prices were held constant at \$500/ton in all simulations. NO_x emission prices were applied on all thermoelectric generation units in the ERCOT region, and were simulated based on generator-specific emission rates. As discussed above, these price scenarios need not necessarily be induced by emissions taxes, but could equivalently represent the result of tighter caps on aggregate NO_x emissions. The generation redispatching scenarios were simulated for the 24 h of 25 June 2008, which was a moderately high generation day (58 GW peak demand for the day, (1095 GWh total demand over that 24 h period) versus 62.2 GW peak demand for the year (ERCOT 2008)). The model output is hourly MWh for each generation unit in ERCOT for four scenarios plus the base case (the base case NO_x price is \$0/ton). Table 1 shows NO_x and SO₂ emissions rates (ton/day) for each scenario as well as the base case. Table 1 also shows the reductions (ton/day) and the percentage

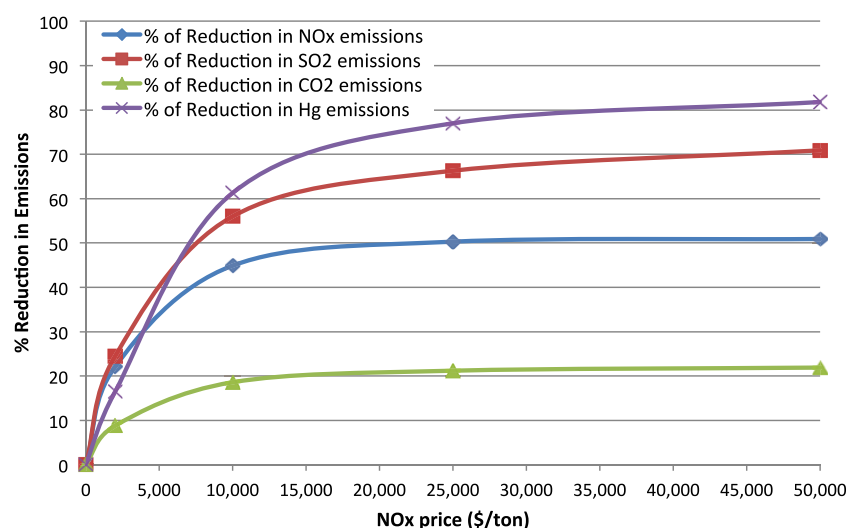


Figure 3. NOx, SO₂, CO₂ and Hg emissions decrease as NOx prices increase.

Table 1. NOx and SO₂ emissions reductions in tons/day for each price scenario relative to the base case.

NOx price (\$/ton)	NOx emissions (tons/day)	Reductions in NOx emissions (tons/day)	% of reduction in NOx emissions	SO ₂ emissions (tons/day)	Reductions in SO ₂ emissions (tons/day)	% of reduction in SO ₂ emissions
0	396.0	0	0	248.1	0	0
2 000	308.5	87.5	22.1	187.2	60.9	24.5
10 000	218.1	177.9	44.9	109.2	138.8	56.0
25 000	196.7	199.3	50.3	83.6	164.4	66.3
50 000	194.2	201.8	50.9	72.2	175.9	70.9

of reductions (%) in NOx and SO₂ emissions for each strategy considered in this study relative to the base case.

All scenarios show reduction in NOx and SO₂ emissions compared to the base case. Reductions in NOx emissions ranged from 22.1% to 50.9% ton/day and for SO₂ emissions ranged from 24.5% to 70.9% ton/day. A NOx price of \$50 000/ton yields the maximum reduction in both NOx and SO₂ emissions. The NOx prices used in this analysis are higher than typical historical NOx pricing. For example, in 2008, the NOx allowance prices ranged from \$1400/ton during the middle of the year to \$600/ton in the end of that year (Federal Energy Regulatory Commission (FERC), derived from Bloomberg data (2011)). Therefore, the NOx prices used in this work range from slightly higher than historical price levels (\$2000/ton) to more than an order of magnitude higher than the typical NOx allowance price. This suggests that in the long term, some mix of dispatching and installation of control equipments is likely the lowest cost option.

The maximum percentage of reduction for NOx and SO₂ emissions for a \$50 000/ton NOx price are 50.9% and 70.9%, respectively. As expected, as NOx emission price increases, so do NOx and SO₂ emission reductions. However, the incremental reductions in NOx emissions between \$25 000/ton and \$50 000/ton was relatively small, as shown in figure 3. Therefore increases in NOx prices beyond \$50 000/ton were not considered.

These reductions in NOx and SO₂ emissions rates are mainly due to shifting electricity generation from coal-fired units and old natural gas units, to low emitting generators

Table 2. The amount of coal generation (MWh) that shifts to natural gas generation in each scenario.

NOx price (\$/ton)	% of generation by coal-fired EGUs	Total amount of generation (MWh) shifted from coal to NG	% of coal generation (MWh) shifted (% of total generation)
0	28.5	0	0
2 000	22.5	64 900	5.9
10 000	11.8	182 000	16.6
25 000	8.1	223 000	20.4
50 000	6.6	239 000	21.9

(typically efficient natural gas-fired units). For example, table 2 shows that coal generation is reduced from 28.5% to 6.6% of total generation as NOx price increases from \$0 to \$50 000/ton.

Table 3 and figures 4 and 5 show the impacts of imposing higher NOx prices on the NOx emissions of coal and natural gas generators.

Figure 5(a) shows that as NOx prices increase from zero to \$2000/ton, generation shifts from moderate (~1–3 lb/MWh) emission coal plants to very low emission (<0.5 lb/MWh) gas plants. Some reductions also occur in high emitting gas plants (~6 lb/MWh). This trend of shifting from coal to natural gas continues as prices increase to \$10 000/ton of NOx. However, no further reductions in high emitting gas plants are possible, so the overall emissions from natural gas units begins to increase. NOx reductions from natural gas reach their peak

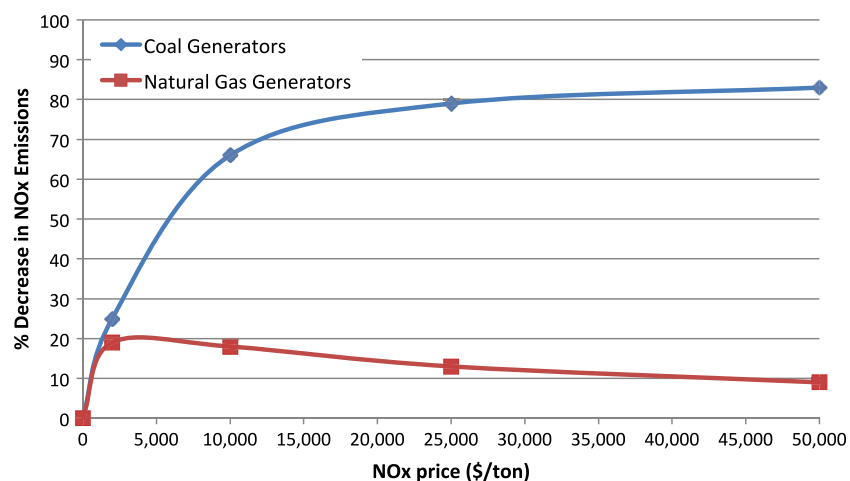


Figure 4. Percentage change in NOx emissions for coal and natural gas generators. Natural gas emissions initially decrease due to reductions in generation from a small number of gas plants with high NOx emissions, but then increase as generation shifts from coal to natural gas.

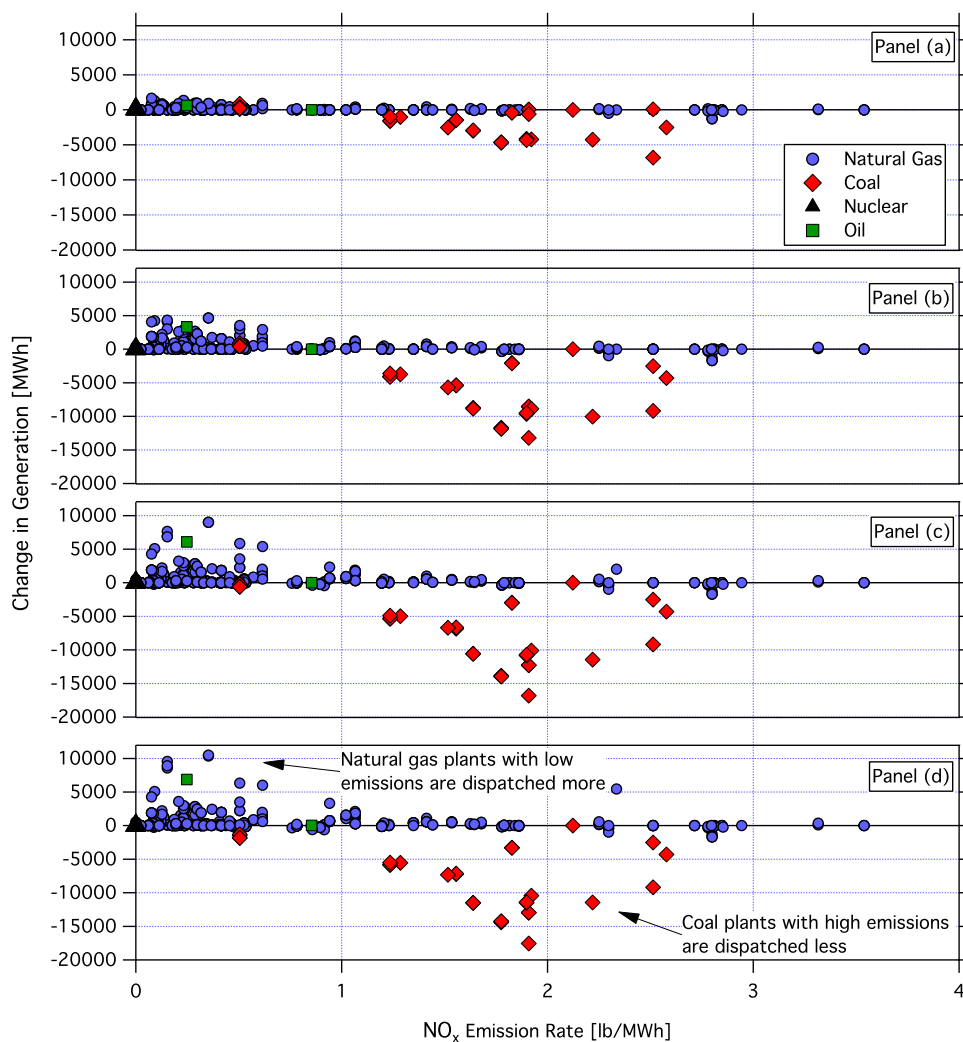


Figure 5. Changes in generation patterns as NOx price increases. Positive changes indicate that generation increases relative to the base case (zero price for NOx) and negative changes indicate that generation decreases. Top panel (a) is for \$2000/ton; (b)–(d) represent \$10 000, \$25 000 and \$50 000/ton respectively. Results indicate that generation generally shifts from moderate (~ 1 – 3 lb/MWh) emission coal plants to low (< 1 lb/MWh) emission gas plants, although some high emission plants remain relatively unchanged even at high NOx prices.

Table 3. Percentage change in NOx emissions for alternative redispatching scenarios relative to the base case for both coal and natural gas generators.

NOx price (\$/ton)	% change in NOx emissions	
	Coal generators	Natural gas generators
0	0	0
2 000	−25	−19
10 000	−66	−18
25 000	−79	−13
50 000	−83	−9

at \$2000/ton, a price large enough to drive reductions in high emitting gas plants.

3.2. Co-benefits

In the United States, carbon dioxide (CO₂) emissions due to fossil fuel combustion are the greatest source of greenhouse gases, and account for 80.2% of the total GHG emissions nationwide (US Climate Action Report 2010). Electricity generation contributes 39% of the total CO₂ emissions and a third of the total GHG emissions (US Climate Action Report 2010). In addition, power plants are responsible for a significant fraction of anthropogenic Hg emissions into the atmosphere (EPA 2002). Therefore, impacts of dispatching to achieve NOx emissions reductions on CO₂ and Hg emissions from EGUs were also examined. Table 4 lists CO₂ and Hg emissions reductions (ton/day for CO₂ and lb/day for Hg) and percentage reductions. Maximum percentage reductions in CO₂ and Hg emissions rates are 21.9% and 81.8% respectively as shown in figure 3 and table 4.

The impact on water consumption of imposing higher allowance prices on NOx was also examined. The electric power system model output was used in addition to the Texas Water Development Board consumption factor (gal/kWh) to calculate water consumption for each EGU. The water consumption factor in the Texas Water Development Board

(TWDB) report, described by King *et al* (2008), estimates the water consumption for the whole power plant so it was assumed that all the electric generation units in the same power plant facility would have identical consumption factors. On average, the natural gas fleet requires less cooling water than the coal fleet.

Daily water consumption (m³/day) and percentage reductions in water consumption were estimated for each scenario relative to the base case. The results indicate reduced water consumption from electricity generation units when higher NOx emission prices are imposed. As shown in table 5, scenarios exhibited different percentages of reductions in water consumption, with maximum benefit (8.7% reduction) achieved when NOx price was equal to \$50 000/ton. The general trend is that any increment in NOx emission prices will lead to reduction in total water consumption. Electricity redispatching due to imposing higher NOx emission prices has the ability to reduce total water consumption by as much as 63–125 (×1000 m³/day) as shown in table 5. Also, table 5 shows the additional number of people who would have access to municipal water use (daily use at 138 gal/person; 0.53 m³/person) based on the water saved due to electricity redispatch, depending on watershed location and seasonal timing of the reduced water consumption at EGUs. NOx price increases over \$10 000/ton have small changes in power plant water consumption.

3.3. Costs of emissions reductions

The cost of NOx emissions reductions from the redispatching strategy are shown in table 6. Table 6 shows the cost per ton of NOx emissions reduced (added \$/ton NOx reduced) and the added cost of each MWh generated (added \$/MWh, equation (2)). Also shown, in figure 6, are the emissions price revenues (NOx price times emissions), although this additional cost would only occur under an emissions tax, not under a cap and trade system. For initial increases in NOx price, generation costs increase due to the higher fuel price of gas relative

Table 4. CO₂ and Hg emission reductions in tons/day for each scenario relative to the base case.

NOx Price (\$/ton)	CO ₂ emissions (tons/day)	Reductions in CO ₂ emissions (tons/day)	% of reduction in CO ₂ emissions	Hg emissions (lb/day)	Reductions in Hg emissions (lb/day)	% of reduction in Hg emissions
0	633 913	0	0	20.7	0	0
2 000	578 297	55 616	8.8	17.3	3.4	16.5
10 000	515 982	117 931	18.6	8	12.7	61.3
25 000	499 522	134 391	21.2	4.8	15.9	77
50 000	495 034	138 879	21.9	3.8	16.9	81.8

Table 5. Percentage reductions in water consumption for alternative redispatching scenarios relative to the base case.

NOx price (\$/ton)	Daily water consumption (×1000 m ³ /day)	% of reduction in water consumption	Savings in total water consumption (×1000 m ³ /day)	Human equivalent
0	1433	0.0	0	0
2 000	1370	4.4	63	120 000
10 000	1315	8.3	118	220 000
25 000	1311	8.6	123	230 000
50 000	1308	8.7	125	240 000

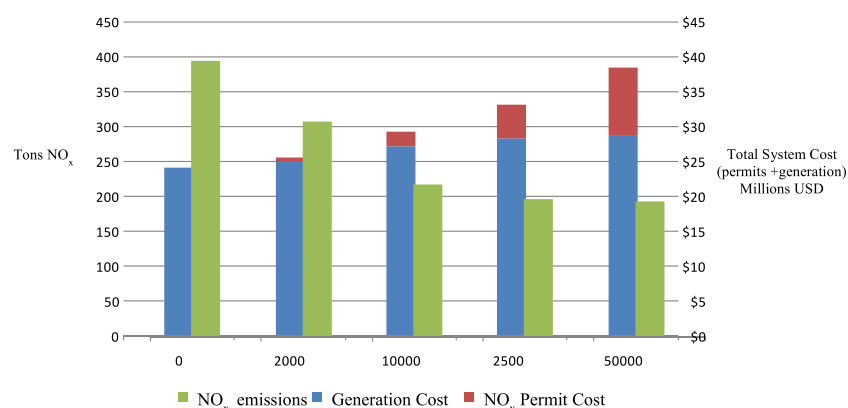


Figure 6. Total NOx emissions, generation costs, and NOx permit costs as permit prices increase. At higher NOx permit costs, the NOx emissions are relatively lower and the generation costs are relatively higher.

Table 6. The cost of electricity generation for each scenario relative to the base case.

NOx price(\$/ton)	Redispatch cost (\$/ton NOx)	Cost per MWh (\$/MWh)	Change in total cost (%)
0	0	0	0
2 000	9 670	0.77	4
10 000	17 060	2.77	13
25 000	20 837	3.79	17
50 000	23 330	4.30	20

to coal that was used for this analysis. However, at NOx prices of \$25 000/ton and above, there is no longer additional significant redispatching because the lower NOx emitting gas units are being utilized; the remaining gas units would have NOx emissions rates that are closer to those in coal units. The fuel price drives the overall cost and significantly reduces the redispatching because gas has higher fuel price than coal. Thus, beyond a NOx price level of \$50 000/ton, increases in NOx prices would increase the emissions fees, but not achieve any substantial reduction in emissions (see figure 6).

4. Conclusions

The analyses presented in this study indicate that dispatching of electricity generation from high NOx EGUs to low NOx EGUs, essentially switching from coal to gas generation, could achieve up to a 50% NOx reduction without requiring the investment costs or delays involved in installing new pollution control equipment. The switch from coal to gas would have additional benefits of decreased SOx, Hg, and CO₂ emissions. Perhaps especially critical in a time of extreme droughts, water consumption by power plants will also decrease (Poumadere *et al* 2005, Stillwell *et al*, 2011b, 2011a). The extent to which dispatching can occur depends on demand, available capacity, and transmission capabilities, and is likely different in other regions of the country. The scenarios considered here are for a period of moderately high peak demand (58 GW) for ERCOT in 2008. Flexibility tends to decrease as loads increase, so dispatching could be more or less effective than predicted here, depending on the daily demand. The market-based

system simulated is hypothetical, and the implementation of such a system would require a change to the current regulatory system. The illustration presented is intended to demonstrate that such options could be considered alongside other regulatory changes.

Acknowledgment

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